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ALTERNATIVES

4.1 INTRODUCTION AND OVERVIEW

This chapter begins with an overview of the context within which the California Energy Commission (CEC) conducts its review of alternatives to the satisfaction of the Warren-Alquist Act and the California Environmental Quality Act (CEQA). It then reviews the criteria and objectives that led to the selection of the site and design of the proposed El Segundo Power Redevelopment (ESPR) Project, and evaluates a wide range of alternatives to the plant as proposed, and to key elements in the design of the project.

This alternatives assessment does not take place in isolation during the facility siting process. The environmental quality evaluations and policy judgments imbedded in the CEC's planning decisions are supported by master assessments that have been prepared to guide the CEC's decisions at the programmatic level. Such assessments include maps of current plant sites, analyses of air quality impacts, renewable resource assessments, energy efficiency strategies, and evaluations of technical issues affecting plant and transmission infrastructure sitings. In addition, the restructuring of the electricity market in California has opened new avenues beyond the siting process for considering and promoting preferred energy measures and technologies. For instance, research and development into new renewable energy and energy efficiency technologies are now supported through a public benefits fund, as are a number of energy efficiency programs. The state's renewable energy fund and customer choice also provide new financial incentives to pursue green electricity projects. All of these developments need to be internalized into the process of alternatives assessment during power plant siting proceedings.

CHAPTER ORGANIZATION

This chapter is organized in the following order:

- Project Objectives (4.2)
- Summary Project Description (4.3)
- Consideration of the No Project Alternative (4.4)
- Consideration of Alternative Generating Technologies (4.5)
- Consideration of Alternative Site Locations (4.6)
- Consideration of Alternative On-Site Configurations and Technologies (4.7)
- Comparative Analysis of Alternatives (4.8)
- Conclusion (4.9).

Context and Structure of Alternatives Analysis.

The alternatives analysis in this chapter focuses on "alternatives capable of eliminating any significant adverse environmental effects or reducing them to a level of insignificance," including evaluation of a "no project" alternative, California Code of Regulations, Title 14, § 15126(b), (e). The analysis is governed by "rule of reason" that requires the Environmental Impact Report (EIR), or EIR-equivalent document, to set forth only those alternatives necessary to permit a reasoned choice; the analysis need not consider an alternative whose effect cannot be reasonably ascertained and whose implementation is remote and speculative, Cal. Code Regs., tit. 14, § 15126(f).

Given the context within which this project is being pursued, Applicant does not anticipate that the El Segundo Power Redevelopment Project will result in significant environmental impacts. Indeed, the location of the project at an existing power-generating site is intended to avoid the potential impacts associated with development and operation of a greenfield power plant. Because the proposed project is a modification of an existing industrial facility, under California Public Resources Code § 25540.6(a)(2) and (b), the project is exempt from the notice of intention requirement, as well as the requirement to provide an evaluation of alternative sites. Since the project involves optimizing the use of the existing ESGS and its infrastructure, any off-site alternative would almost inevitably result in increased environmental impacts resulting from the need to construct an alternative power generation facility and its supporting infrastructure.

Applicant recognizes, however, that even while § 25540.6 and AB1884 limiting the information required to be provided by an applicant in an Application for Certification (AFC), the regulations do not relieve the Commission of its responsibility under CEQA to conduct an alternatives analysis in relation to a proposed power redevelopment project. CEQA, itself, delimits the scope of the alternatives analysis through project definition and feasibility considerations. As a result, Applicant has attempted to provide as complete a picture of the alternatives issue as possible.

As a matter of first principle, CEQA contemplates that approval of any action that may have a significant adverse effect on the environment must be predicated on a demonstrable social need for the proposed action, and on a review of reasonable alternatives that might avoid or substantially reducing any significant adverse environmental effects. This chapter will allow the Commission to fulfill this CEQA responsibility. Applicant believes that in providing such a comprehensive review, the analysis more than satisfies the letter and intent of the relevant CEQA and Warren-Alquist Act requirements.

4.2 PROJECT OBJECTIVES

Applicant's business strategy involves the purchase and repowering of existing but antiquated generating facilities. The ESPR Project, an example of this strategy, has the following objectives:

- The production of cost-effective electricity to compete in California's deregulated electricity markets
- To improve the overall environmental performance and reliability of the electrical generating sector in Southern California
- To produce electricity with minimal environmental impacts
- To alleviate the consequences of today's capacity shortage in Southern California
- To assist in meeting the projected demand growth in Los Angeles County.

4.3 PROJECT DESCRIPTION

The ESPR Project will be constructed and operated without ratepayer support as a "merchant plant." The project will supply 630 MW of capacity and energy to California's restructured electric market. Applicant anticipates the new combined cycle unit's output will be sold both into the California Power Exchange and to large wholesale customers.

The most notable feature of the proposed project is its location at the existing El Segundo Generating Station (ESGS) and its efficient use of the resources on ESGS. ESGS has been operating as an electric generating station since May 1955. The facility is currently comprised of four gas-fired conventional, electric power generating units. The oldest units of the ESGS facility, Units 1 and 2, continue to be used for peak power needs given the advantageous load-center location of the facility. The plans for the proposed project include demolition of the existing power blocks of Units 1 and 2, and construction of a 3-unit combined cycle plant within the footprint of the demolished units. The new Units 5, 6, and 7 will be capable of providing significantly more power to the region, with higher reliability and at lower cost, from the same project footprint and environmental envelope.

The project's location at an existing power generation facility in a larger industrial complex has important business and environmental advantages. For example, it will be able to draw upon an existing pipeline to supply sufficient natural gas, and an existing ocean water cooling system. And although the project will require ammonia for pollution control purposes, the ammonia will come by pipeline from the adjacent Chevron refinery, eliminating the need for alternative ammonia transport to the plant site.

4.4 NO PROJECT ALTERNATIVE

According to CEQA, "The purpose of describing and analyzing a no project alternative is to allow decision makers to compare the impacts of approving the proposed project with the impacts of not approving the proposed project," Cal. Code Regs. Tit. 14, §15126.6(e). The no project alternative analysis, therefore considers existing conditions and the foreseeable impacts of not approving the project.

The no project alternative for this application is that ESGS units 1 and 2 would not be demolished and the combined-cycle plant, comprised of Units 5,6, and 7 would not be added. ESGS would continue operating the existing Units 1 and 2 for peaking purposes. 280 less megawatts would be made available in the Western Los Angeles Basin.

The no project alternative would inevitably exacerbate recent power market conditions in California, which have been characterized by involuntary power curtailments and price escalations. To address these adverse conditions, a number of entities including the Federal Energy Regulatory Commission, the California Independent System Operator, the California Public Utilities Commission and the Electricity Oversight Board, the California Power Exchange, and the CEC have examined the root causes of these factors. All of these organizations found that the following factors contributed to the curtailments and high prices:

- Above normal temperatures
- High natural gas prices
- Reduced imports due to increased demand in the Southwest and the Pacific Northwest
- An aging fleet of power plants
- New regulations allowing California based generators to sell power outside of the state
- A sustained increase in load growth relative to new generating capacity.

The no project scenario would exacerbate the current dysfunctional market conditions characterized by weak levels of reliability, and rising power prices. In addition, it is contrary to the findings of both AB 1890 and SB 110, which both emphasize the need to site new power plants that increase reliability, improve the environmental performance of the electricity industry, and reduce consumer costs. This set of objectives is ideally advanced by the proposed project, which involves the modernization and expansion of the existing generation system, and the efficient use of regional infrastructure and energy resources that can be expected to lower electricity costs and increase overall system reliability. This is particularly true given the load-center location of the proposed facility.

4.4.1 Increased Transmission

Additionally, under the no project alternative the present transmission system transfer capability of ESGS and other power sources supplying the region will remain the same regardless of load conditions. Currently the Western Los Angeles Region, as well as the Greater Los Angeles load basin, is served by a combination of power plants and transmission facilities. Currently both are reaching, or approaching, the maximum capacity during peak demand capabilities. Thus, failure to expand generation intrinsically leads to the need for additional transmission facilities.

However, siting new transmission capacity into the immediate load center of ESGS would result in a number of environmental impacts associated with the plant's urban location. The construction of a new line in Los Angeles County would impose adverse land use, view shed, and noise impacts that would at least in part offset lack of project impacts.

4.4.2 Continued Dependency on Aged, Unreliable Units 1 and 2

The increased dependence on Units 1 and 2 would result from the No Project Alternative. Units 1 and 2 are aged units that are reaching the end of their useful life. They are less efficient and less reliable than the ESPR Project. The No Project Alternative would have higher impacts to reliability and efficiency of electricity generation.

4.4.3 Greater Impacts Per Megawatt Produced

The No Project Alternative leaves in operation the aged, lower efficiency Units 1 and 2 instead of the higher efficiency, lower pollutant emitting Units 5, 6 and 7. The key feature of ESPR is its use of ESGS and essentially what is the environmental envelope for Units 1 and 2, to produce nearly twice the amount of power. Additional generation, both on a peaking basis and on a daily load basis, would intrinsically have more impacts by virtue of the very low incremental impacts of increasing the power produced from the resources that serve Units 1 and 2. These resources which are used more efficiently by ESPR are:

1) Ocean water used for cooling purposes
2) Biological resources impacted by Units 1 and 2
3) Visual resources affected by Units 1 and 2
4) Natural gas consumed to produce electricity
5) Potable water used by Units 1 & 2
6) Ocean water affected by sanitary discharge of ESGS.

4.4.4 Conclusion

The analysis of the No Project Alternative clearly shows that ESPR has less impacts than the No Project Alternative. Clearly under those circumstances ESPR meets the "No-Project Alternative" scrutiny required by CEQA.

4.5 CONSIDERATION OF ALTERNATIVE GENERATING TECHNOLOGIES

The ESPR plant will be a merchant plant as defined by the CEC. As a merchant plant, ESPR will be competing with other electricity generators selling electricity in the deregulated market. The natural gas-fired combined-cycle technology proposed for use for the ESPR project was selected based on applicant's assessment of what technology would most

effectively generate cost-effective and highly reliable capacity and energy to Southern California. Since a combined-cycle facility also results in an exceptionally clean and efficient use of natural gas resources, use of this generating technology will allow ESGC to be competitive as a merchant plant for years to come.

The purpose of considering alternative generating technologies is to determine if any of the technologies could potentially avoid or substantially reduce any significant environmental impacts of the proposed natural gas-fired combined-cycle facility. Other technologies were considered using the selection methodology described below.

4.5.1 Selection Methodology

Technologies considered for this analysis emphasize those that could provide both base load power and peaking power in order to economically sell electricity in the deregulated market at the lowest cost, yet be able to take advantage of rapidly changing market conditions. A plant designed as either a base load only or a peaking plant only would expose the project to the risk of market changes, as the type of demand and competition changes over time in the deregulated market. Two intermittent technologies, solar and wind, were examined to determine if they would be viable alternatives to the proposed facility. Specific evaluation criteria used in the alternatives analysis are:

Commercial Availability: Any viable technology has to have been proven commercially available at an acceptable cost;

Implementability: The technology has to meet environmental, public safety, public acceptability, fuel availability, financial, and system integration requirements;

Cost Effectiveness: The technology has to be cost competitive with existing power generating facilities, and facilities that are expected to enter the market at the time the proposed project begins commercial operation, and for the thirty-year life of the project thereafter. Costs considered include capital, operating, and maintenance costs.

The technologies reviewed were grouped according to fuel used, namely oil/natural gas, coal, nuclear, hydro, and solar photovoltaics and wind.

4.5.2 Natural Gas-Fired Conventional Combined-Cycle

This technology integrates gas turbines and steam turbines to achieve high fuel efficiencies. The gas turbine drives a generator. The exhaust gas from the generator is routed through a heat recovery steam generator to create steam used to drive a steam turbine-generator. Efficiency for this type of system is typically 50 to 58 percent, resulting in lower air emissions per kilowatt-hour than simple gas turbine systems or conventional boiler-steam systems. In addition, natural gas combustion in a state-of-the-art combined-cycle unit emits less emissions such as NOx, CO, volatile organic compound (VOC), sulfur dioxide and particulate matter. Because of its high efficiency, clean air emissions, and lower generation costs, this technology was selected for the proposed El Segundo plant repowering.

4.5.3 Natural Gas-Fired Conventional Furnace/Boiler Steam Turbine- Generator

With this technology, oil or natural gas fuel is burned in a boiler to create steam, which is routed through a steam turbine that powers a generator. The steam is condensed and returned to the boiler. This technology is less efficient (35 to 40 percent) than combined-cycle technology and emits more air pollutants per kilowatt-hour generated. Due to the large size and complex nature of the equipment required, the capital costs and time to construct are greater. In addition, the cost of generation is comparatively high. Based on lower plant efficiency, higher emissions per MWh generated, higher capital costs, and increased labor costs to operate and maintain the facility, this technology was eliminated from consideration. This technology alternative also does not offer the potential of reducing the environmental impacts of the selected natural gas combined-cycle technology.

4.5.4 Natural Gas-Fired Supercritical Boiler Steam Turbine-Generator

This technology is similar to conventional boiler steam turbine technology, but higher pressures and temperatures are employed. The efficiency of this technology is higher than conventional boiler steam turbine-generator systems (generally 38 to 45 percent), but additional capital costs are incurred to construct the generating units. As a result, the costs to produce power using supercritical technology are somewhat lower than conventional technology, but higher than natural gas-fired combined-cycle technology. Based on lower plant efficiency, higher emissions per MWh generated and higher capital and operating costs, this technology was eliminated from consideration. This technology alternative also does not offer the potential of reducing the environmental impacts of the selected natural gas combined-cycle technology.

4.5.5 Natural Gas-Fired Simple-Cycle Gas Turbine

This technology uses a gas turbine to drive a generator, and exhausts high temperature gas directly to the atmosphere. Simple-cycle gas turbines have a low capital cost, have efficiency approaching 35 to 40 percent in larger units, and are fast starting. Air quality impacts are higher with this technology than combined-cycled units because the high exhaust gas temperatures make it difficult to control NOx, CO, and VOCs, and because more fuel must be burned to produce the equivalent amount of power as compared to a natural gas-fired conventional combined-cycle facility. The capital cost of installation would be the lowest of all options considered, but the cost of generation for a base load facility would be high with this technology due to poor fuel efficiency, leading to high operating costs that more than offset the benefits of lower installed capital costs. Due to its relatively low efficiency (compared to combined-cycle designs), potential limited run hours due to merchant plant economics, and higher electricity generation cost, this technology was eliminated from consideration. This technology alternative also does not offer the potential of reducing the environmental impacts of the selected natural gas combined-cycle technology.

4.5.6 Kalina Combined-Cycle

This technology is similar to conventional combined-cycle technology except water in the heat recovery boiler is replaced with a water and ammonia mixture. The overall efficiency of this technology is approximately 10 to 15 percent greater than conventional combined-cycle technology. This technology is still in the testing phase and is not currently commercially available. Therefore, this technology presents many financial risks that could impede the long-term viability of the project relative to the proposed technology and was eliminated from consideration.

4.5.7 Advanced Gas Turbine

There are a number of advanced gas turbine technologies that have been developed to enhance the performance and/or efficiency of gas turbines, one of which has been developed by the Commission, the California Cycle. These include humid air turbines, chemically recuperated gas turbines, steam injected gas turbines, and intercooled steam recuperated gas turbines. With the exception of steam injected gas turbine technology, none of the technologies are fully commercially available. Steam injected gas turbine technology is marginally commercially available, but its efficiency is lower, and its emissions are higher than conventional combined- cycle technology, thus unable to meet the strict emission criteria of the Southern California area. Because long-term viability, efficiency, and emissions are of a greater concern than is the case with the proposed technology, these technologies were eliminated from consideration.

4.5.8 Fuel Cells

This technology uses an electrochemical process to combine hydrogen and oxygen to liberate electrons and provide a flow of current. The types of fuel cells include proton exchange membrane, solid oxide, alkaline, molten carbonate, and phosphoric acid. With the exception of the phosphoric acid and molten carbonate fuel cells, these technologies are not commercially available. The phosphorous acid fuel cell technology has operated at only smaller size units and molten carbonate fuel cell technology has just completed the testing phase. In addition, neither of these technologies is currently cost competitive with conventional combined-cycle technology. Since fuel cell technologies are unable to provide generation on a scale that offers comparable reliability and cost-effectiveness as the proposed unit, they were not considered a reasonable alternative.

4.5.9 Coal or Other Solid Fuel-Fired Conventional Furnace/Boiler Steam Turbine-Generator

With this technology, coal, coke or other solid fuels are burned in the boiler, creating steam that is passed through a steam turbine connected to a generator. The steam is condensed and returned to the boiler. The efficiency of this technology is equivalent to a conventional gas fired boiler/steam turbine unit (35 to 40%). However, siting such a plant in California would require importing coal into the state resulting in increased truck and/or train traffic, and coal storage issues. Further, the coal plant would require a greater area and produce more emissions than a natural gas facility of equivalent capacity. A comparable scale coal plant would also result in higher capital and operating costs than the proposed combined-cycle gas-fired facility. For these reasons, this technology was eliminated from consideration.

4.5.10 Atmospheric and Pressurized Fluidized Bed Combustion

These technologies burn coal or other solid fuels in a hot bed of inert material containing limestone that is kept suspended or fluidized by a stream of hot air. Water coils within the furnace create steam that drives a steam turbine-generator. Atmospheric fluidized bed combustion has an efficiency of 35 to 40 percent, while pressurized fluidized bed combustion has an efficiency of 40 to 45 percent. This technology is currently only commercially available for units up to 300 MW. The CEC was at the forefront of this technology excusing the 100 MW plant from a Need analysis under the RD&D exception. Again, issues involving the importation of coal, the greater plant space required, higher capital and operating costs, and the higher emissions per output compared to natural gas technologies resulted in the elimination of this technology from further consideration. It is highly unlikely that this technology could be sited as an alternative to the proposed facility.

4.5.11 Integrated Gasification Combined-Cycle

This technology gasifies coal to produce a medium Btu gas that is used as fuel in a gas turbine. The coal gasifier is located at the same site as the gas turbine, HRSG, and steam turbine- generator. The use of low or medium Btu coal gas in base-load gas turbines is still in the late demonstration stage. Due to higher capital costs, issues regarding the importation of coal, the lack of commercial experience, and lower plant efficiency leading to higher operating costs, this technology is not competitive with conventional gas-fired combined-cycled technology and was eliminated from consideration. The CEC had before it a restart of the previously approved 110 MV Coolwater IGCC Demonstration Project based on a fuel input of coal/sewer sludge and outputs of electricity, liquid phase methanol (LPMeOH) and CO2. The methanol process was to be a flywheel when electricity prices were low providing for additional fuel for offsite sales. The project was withdrawn from the Commission because of concerns that it would require too high an RD&D incentive payment, was incompatible with the CPUC's BRPU, and would exacerbate the existing judgement of too much generation. The price for IGCC output at that time was in the low cents per kilowatt-hr range. In any event, it is highly unlikely that this technology could be sited as an alternative to the proposed facility.

4.5.12 Nuclear Fission

This technology breaks atomic nuclei apart using various types of reactors, giving off large quantities of energy. Pressurized water reactors and boiling water reactors are commercially available, but high temperature gas cooled reactors and liquid metal fast breeder reactors are not. California law prohibits new nuclear power plants until the scientific and engineering feasibility of radioactive waste disposal has been demonstrated. Consequently, this technology is not a feasible alternative to the gas-fired combined-cycled unit proposed by the project.

4.5.13 Hydroelectric

This technology uses falling water to turn turbines that are connected to generators. A dammed or flowing river is required to obtain the falling water. This technology is commercially available; however, most of the sites, within California, ideal for hydroelectric technology have already been developed. Further, hydroelectric sites generating 630 MW of power would require the inundation of thousands of acres of land with water, generating extensive biological and environmental impacts. It is highly unlikely that this technology could be sited as an alternative to the proposed facility. Therefore, this alternative was rejected from further consideration.

4.5.14 Geothermal

This technology uses steam or high temperature water obtained from naturally occurring geothermal resources to power steam turbines. However, there are no geothermal resources of a sufficient size in the Los Angeles County area to make this technology a feasible alternative to the proposed project.

4.5.15 Solar/Photovoltaics

These technologies either collect solar radiation to heat water to create steam, which drives a steam turbine, or convert solar energy directly, using a silicon wafer. Several systems that have been used in the U.S. capture and concentrate solar radiation with a receiver. The three main receiver types are mirrors located around a central receiver, parabolic dishes, and parabolic troughs. With the exception of parabolic troughs, these receiver technologies are not commercially available. Photovoltaic technology uses silicon cells to convert solar radiation to direct current electricity, which is then converted to alternating current. While photovoltaic technology is commercially available, the cost to operate is high, generally 15 to 25 cents per kilowatt-hour.

These technologies would require large land areas in order to generate the proposed 630 MW net at ISO conditions. For example, centralized solar projects using parabolic trough technology require approximately five acres per MW. The land requirement to produce similar capacity as the proposed project is 3,400 acres. Photovoltaic arrays require similar acreage per MW. Due to the large land area required by these technologies and the high costs to operate them, these technologies were eliminated from consideration for alternative purposes.

4.5.16 Wind Generation

This technology uses a wind-driven propeller to turn a generator and generate electricity. The costs of electricity at approximately 4 cents per kWh would be greater than the proposed project. Additionally, a centralized wind facility would require 40 to 50 acres per MW. A 630 MW wind facility would require 25,2000 acres as compared to the 5.5 acres proposed by the project. Further, such a facility would have extensive visual and noise effects, in addition to increasing the risk of avian mortality. This technology also does not have a sufficient capacity factor that successfully addresses the Los Angeles Basin’s need for reliable baseload power. These size, environmental and reliability concerns associated with this technology resulted in its elimination from further consideration.

4.5.17 Biomass

Direct combustion, gasification, and anaerobic digestion are the technical alternatives used to convert biomass fuels to electricity. Major biomass fuels include wood wastes, agricultural residues, and municipal solid waste. The scale of commercially available biomass facilities ranges from 5 to 25 MW, which is incompatible with the objectives of the project. Further, such facilities can produce significant air emissions; require fuel deliveries by truck; and, in the case of waste-to-energy facilities, generate concern over the release of toxic emissions. The capacity limitations and potential environmental implications associated with biomass facilities resulted in its elimination for further consideration as a feasible alternative generating technology. It is highly unlikely that biomass resources of the scale needed could be sited as an alternative to the proposed facility.

4.6 ALTERNATIVE SITE LOCATIONS

Given the fact that the proposed project involves repowering an existing generating facility, once it was decided to purchase the ESGS facility, Applicant had no cause to evaluate potentially alternative facility sites in the immediate area of the proposed project. Applicant’s business strategy is premised on the repowering of the facility; construction of a greenfield power generating facility is not part of the company’s business strategy in this case.

Nevertheless, Applicant can specify key criteria used in evaluating alternative repowering investment opportunities:

- Capable of hosting a cost-competitive and commercial scale repowered merchant power plant

- Ability to acquire site control

- Access to existing support infrastructure, particularly gas pipeline and transmission interconnection access
- Ability to minimize potential environmental impacts associated with the repowering
- Maximum compatibility of the proposed project with surrounding land uses.

There are very few, if any, alternative sites in the area that can reasonably satisfy these criteria. The ESGS site, however, offers an ideal match to the above criteria.

Constructing an alternative project scenario to the proposed repowering would involve not just an alternative site, but an entirely different project approach. Indeed, it would require replacing the proposed facility with a greenfield power plant of approximately the same size. While potentially feasible, this alternative would almost inevitably result in greater environmental impacts than those associated with the proposed repowering project. The construction of a new plant would require the development of new infrastructure in an already heavily urbanized region, while the proposed facility takes advantage of key existing infrastructure and fits within the footprint of an already existing facility. Further, a project sited inland of the currently proposed site would require identifying a major new source of cooling water for the project.

As a result of these factors, there is no reason to suspect that an alternative location for an alternative 630 MW greenfield facility would have the ability to significantly mitigate any significant environmental impacts of the proposed facility. Particularly since it is expected that the proposed facility will not result in any findings of environmental significance.

4.7 CONSIDERATION OF ALTERNATIVE ESGS CONFIGURATIONS AND TECHNOLOGIES

4.7.1 Plant Configurations/Arrangements

The El Segundo Power Redevelopment Project will involve the complete demolition and removal of Units 1 and 2 on the ESGS site, except for the steam cycle heat rejection system, which utilizes water from Santa Monica Bay. Units 5, 6 and 7 will be constructed in the location previously occupied by Units 1 and 2. As Units 3 and 4 will not be removed and continue to operate during the proposed project, the power block of the new units (i.e., two combustion gas turbines (CTGs), two Heat Recovery Steam Generators (HRSGs) and associated exhaust stacks and the single steam turbine (ST)) will be constructed in an area of approximately 5.5 acres. The area is so constrained that vertical HRSGs will be required by this configuration instead of the more widely used horizontal HRSGs. This arrangement of 2

CGTs and 1 ST is the only design to afford optimum use of this small amount of property. Therefore, no other alternative onsite arrangements of this equipment are considered.

4.7.2 Replacement of the Existing Boilers

In this alternative, the existing equipment would simply be replaced in kind. While the opportunity to reduce fuel consumption and air emissions per unit of output exists, it is only able to achieve a maximum thermal efficiency of 30 to 40 percent, much lower than the proposed configuration. Due to its relatively lower efficiency, it tends to emit a greater quantity of air pollutants per kilowatt-hour of power generated than more efficient technologies such as the proposed combined-cycle unit. Furthermore, its cost of generation is relatively high, making it uneconomical to operate in a merchant plant environment. Therefore, this alternative is not considered viable.

4.7.3 Other Base Load Combined-Cycle Capacity

This analysis considers the implications of pursuing a smaller or a larger project alternative to the proposal. The smaller alternative is defined as the installation of a single 250 MW unit, while the larger option considers the installation of three new units, each with a capacity of 300 MW.

An alternative of a single unit of approximately 250 MW (1 new gas turbine) would achieve a portion of the benefits of the proposed project while incurring most of the same impacts. The smaller 250 MW size plant would incur higher capital costs per MW installed for infrastructure and project development activities and higher operating costs per megawatt hour (MWh) generated for labor and other fixed operating costs. This increased cost would make financing the project more difficult and at a greater expense and result in a project with less ability to generate energy economically in the California merchant market. In addition, the environmental footprint of a single-unit facility would not be dramatically less than that of the larger facility.

A larger plant (3 units of approximately 300 MW each) than the proposed project was also evaluated. While this alternative would, in theory, take advantage of economies of scale, the larger plant would require more additional space than is available on the current site (5.5 acres) of El Segundo Units 1 & 2. Additionally, this alternative would require water resources beyond those for which the site is already permitted, and generally increases the other impacts of the project. Clearly, such an alternative would not significantly mitigate any potential impacts of the proposed facility.

4.7.4 Alternative Wastewater Disposal Options

Several wastewater disposal alternatives were evaluated during the preliminary project development stages. These alternatives included zero-discharge disposal, sending wastewater to the city sewer, and discharging all wastewater directly to the ocean after onsite treatment, which is the current method of disposal for Units 1 and 2.

Wastewater from the proposed combined cycle plant at ESGS includes stormwater runoff, miscellaneous plant and equipment drains, and blowdown from both the combustion turbine inlet air evaporative coolers and the heat recovery steam generators (HRSG). Sanitary sewage is also a waste stream that will require disposal. Table 4.7-1, "Summary of Plant Wastewater Streams," provides a summary of sources of wastewater and the estimated quantities produced during average and peak operation.

TABLE 4.7-1

SUMMARY OF PLANT WASTEWATER STREAMS

Wastewater Source	Average Usage [1] (gpm)	Peak Usage [2] (gpm)
Site Stormwater Runoff	2	2
Miscellaneous Plant Drains	18	18
Evaporative Cooler Blowdown	10	20
HRSG Blowdown/Quench Water	42	64
Sanitary Wastes	1	1

1 Daily average usage based on 59°F average annual ambient temperature, the HRSGs not fired, no steam injection to the CTGs, evaporative coolers on, assumed for 24-hour day.

2 Peak usage based on 83°F ambient temperature, the HRSGs fired, 12 hours of steam injection to the CTGs, evaporative coolers on, assumed for 24-hour day.

In all five plans or alternatives considered, stormwater flows were routed through an onsite oil/water separator prior to being discharged to the Santa Monica Bay through the proposed combined cycle plant once-through cooling water system. In all alternatives but the zero-discharge plan, sanitary sewage was routed to the City of Manhattan Beach sewage system. Wastewater disposal alternatives include the following:

Plan 1 - Discharge all wastewater to the Santa Monica Bay (Pacific Ocean) via the proposed combined cycle plant once-through cooling water discharge. See Figures 3.4-5 and 3.4-6 in Section 3 for a depiction of this water mass balance, which is considered the base case alternative.

Plan 2 - Discharge all wastewater to the local sewer system. Figure 4.2-1 provides the water mass balance diagram for Plan 2.

Plan 3 - Reduce the wastewater volume by the addition of blowdown cooling, recycle within the plant the steam cycle and evaporative cooler blowdown, and route the remaining wastewater to the local sewer system. See Figure 4.2-2 for the Plan 3 water mass balance.

Plan 4 - This plan is the same as Plan 3 with all remaining wastewater routed to a tile field on the ESGS site (i.e., zero-discharge). See Figure 4.2-3 for a depiction of the water mass balance.

Plan 5 - Similar to Plans 3, but with the addition of miscellaneous plant and equipment drains treatment system to recover the wastewater from these plant drains for reuse Figure 4.2-4 provides the water mass balance diagram.

4.7.4.1 Alternatives Description

4.7.4.1.1 Plan 1 – Discharge All Wastewater to Santa Monica Bay (Base Case). In accordance with the current site NPDES permit, wastewater from Units 1 and 2, which includes boiler blowdown, steam cycle blowdown, and oil/water separator effluent from plant and equipment drains, is routed to the existing retention basin that is located south of Units 3 and 4. The effluent from the retention basin is then routed to the once-through cooling system outfall for Units 1 and 2, Discharge Serial No. 001. Septic system “gray water” effluent is discharged directly to the once-through cooling system outfall for Units 1 and 2. Stormwater is currently sent through an oil/water separator before being discharged into the Discharge Serial No. 001 outfall.

In this base case and preferred alternative, the wastewater associated with the proposed combined cycle plant, which include HRSG blowdown and associated quench water, evaporative cooler blowdown, steam cycle drains, and oil/water separator effluent from plant and equipment drains, will be routed to the existing retention basin. The effluent from the retention basin is then routed to the once-through cooling system outfall for Units 1 and 2, when the existing Units 3 and 4 are not operating. During operation of Units 3 and 4, the effluent from the retention basin will be discharged into the Discharge Serial No. 002 outfall.

Stormwater in the area where the proposed plant is to be located will continue to be sent through an oil/water separator before being discharged into the Discharge Serial No. 001 outfall. Sanitary wastes will be connected to the local sewer system that is operated by the City of Manhattan Beach Public Works Department. A lift station and a pipeline will be required to transfer the sanitary sewage to the city sewer.

The wastewater to be discharged to the Santa Monica Bay will be of good quality. The combined wastewater will consist of the following:

- Once-through cooling water from Unit 6 heat rejection system, which is seawater that is periodically treated with sodium hypochlorite for the control of biological growths in the cooling system

- Miscellaneous plant and equipment drains will be primarily city water mixed with small quantities of rainwater (i.e., precipitation collected in area drains). Plant drains that collect water from areas where the potential for oil contamination exists will be treated in an oil/water separator to significantly reduce the amount of oil and grease that is discharged

- Steam cycle drains and HRSG blowdown are high purity water from the steam cycle. HRSG blowdown water is mixed with city water for temperature quenching. This stream will have lower concentrations of dissolved species than city water

- Evaporative cooler blowdown is city water that has been concentrated in the evaporative process of the coolers located in the CTG inlet air system.

The primary disadvantage to this plan is that more water is discharged to the ocean than is withdrawn in the once-through cooling system and monitoring will be required to ensure that discharges are within permitted limits.

4.7.4.1.2 <u>Plan 2 – Discharge All Wastewater to Local Sewer System</u>. For this alternative, all wastewater, except for site stormwater runoff, would be routed to the City of Manhattan Beach sewer system. Complete discharge of both plant wastewater and sanitary sewage to the city sewer system would have the advantage of requiring relatively little additional equipment. A higher capacity lift station and pipeline than that proposed in Plan 1 would be required to transfer the wastewater to the city sewer. This alternate eliminates all discharges of wastewater other than stormwater runoff directly to Santa Monica Bay.

Representatives of the City of Manhattan Beach have advised that it is unlikely that the city sewer system would be able to handle the large quantities (70 to 102 gpm) of wastewater. For this reason, this alternative was deemed to be not feasible.

4.7.4.1.3 Plan 3 – Reduce Wastewater Volume and Discharge to Local Sewer System. In Plan 3, the reduction of the amount of wastewater requiring disposal would be accomplished through the following plant modifications:

- Heat exchangers would be added to cool the HRSG blowdown in lieu of using quenching water. Steam cycle feedwater would be used as the cooling fluid

- The evaporative cooler and HRSG blowdown streams would be reused as feedwater to the steam cycle makeup treatment system. This will reduce the wastewater by reusing these streams that were previously discharged. A reclaim water tank and pumps would be added to allow for collection of the blowdown streams.

This alternative has been determined to reduce the total wastewater to be discharged (excluding sanitary wastes and stormwater runoff) from 70 gpm on an average day and 102 gpm on a peak day to 18 gpm for both average and peak days. The Public Works Department of the City of Manhattan Beach indicated that the city sewer system and/or the Los Angeles County Sanitation District (LACSD) would be able to handle flows of this magnitude. Use of this alternative eliminates the need to discharge wastewater directly to the ocean.

In addition to the equipment noted above, a lift station and pipeline to the city sewer connection point would be required. With this alternative, operating costs for the portable cycle makeup treatment system would increase over that utilized in Plan 1, since the dissolved solids in the water fed to the steam cycle makeup system would be increased by recycling streams to this system. These additional costs would be slightly offset by a reduction in costs due to the reduction in both city water and West Basin Municipal Water District reclaim water consumption.

Disadvantages of this alternative include increased capital expenditure, increased operation and maintenance costs, and adding additional sewer load on the City of Manhattan Beach / LACSD systems with relatively good quality water.

4.7.4.1.4 Plan 4 – Zero-Discharge. For this option, the wastewater volume would be reduced as described in Plan 3. A zero-discharge disposal system would take the wastewater and reduce it by evaporation in a brine concentrator and crystallizer. Effluent from the brine concentrator and crystallizer would then be directed to the cycle makeup treatment system. Because of the limited size of the ESGS site, the complexity of this type of system, and its high capital and operating costs, this type of zero-discharge system was rejected. However, an alternative zero-discharge system was considered.

In this alternative zero-discharge system, the wastewater volume would be reduced as described in Plan 3. The wastewater would then be discharged to a tile field located on the ESGS site in lieu of being discharged to the local sewer system. Although this alternative has

the advantage of reducing the amount of wastewater requiring disposal, there are a number of disadvantages. The associated additional equipment costs would be the same as in Plan 3. This alternative would require a large tile field that would be difficult, if not impossible, to

locate on the existing ESGS site. Also, since the wastewater is being discharged directly to the environment, a NPDES and/or similar permit(s) may be required. Therefore, this alternative zero-discharge plan was also deemed not feasible.

4.7.4.1.5 <u>Plan 5 – Additional Reuse of Plant Wastestreams</u>. With Plan 5, the wastewater volume would be reduced in the same manner as in Plan 3; however, the miscellaneous plant and equipment drains would undergo ultra-filtration to allow their use in the steam cycle makeup treatment system. This would further reduce the amount of wastewater that would require disposal. Sanitary waste would continue to be routed to the city sewer, and site stormwater runoff would continue to be routed to Santa Monica Bay.

In addition to the reuse steps discussed in earlier alternatives, equipment would be added to treat potentially oily drain water prior to recycling this stream to the cycle makeup treatment system. Since the amount of water recycled during average operation would exceed the amount of water required in the steam cycle, HRSG blowdown would be mixed with city water to provide makeup to the evaporative coolers. This would allow the evaporative coolers to be operated at higher cycles and further reduce the station makeup water requirements.

There are a number of drawbacks associated with this alternative. These include the cost of the equipment required for reusing drains wastewater stream, in addition to the equipment cost previously mentioned in for reducing wastewater volume as in Plan 3. The amount of oil and grease remaining after treatment of the plant and equipment drains would have to be nearly negligible to allow for use as makeup water. Chemical treatment may also be necessary to aid in the removal of the oil and grease.

4.7.4.2 <u>Recommended Option</u>

Advantages and disadvantages exist for each alternative. The limited benefits of adding equipment to treat and recycle the wastewater streams are greatly outweighed by the costs and complexity of implementing these options. Refer to Tables 4.7-2 and 4.7-3 for cost impact estimates. The existing facility currently routes all wastewater to Santa Monica Bay for disposal. Alternative Plan 1, "Discharging All Wastewater to Santa Monica Bay" will route all wastewater to the bay and discharge sanitary wastes to the City of Manhattan Beach sewer system. This alternative will not require substantial additional capital and operating expense, and water that is discharged from the facility to the ocean will be similar in composition to city water. As such, its impacts on the environment are minimal. For these reasons, Alternative Plan 1 (Base Case) is the recommended method of handling the wastewater streams.

TABLE 4.7-2

CAPITAL COST ESTIMATE FOR WASTEWATER DISPOSAL PLANS

Plan	Description	Cost Differential from Base Case
1	Discharge all wastewater to Santa Monica Bay (Base Case)	---
2	Discharge all wastewater to local sewer system	Not Feasible
3	Reduce wastewater volume and discharge to local sewer	$744,000
4	Zero-discharge	Not Feasible
5	Additional reuse of plant waste streams	$846,000

TABLE 4.7-3

ESTIMATE OF OPERATION AND MAINTENANCE COSTS FOR WASTEWATER DISPOSAL PLANS

Plan	Description	Cost Differential from Base Case
1	Discharge all wastewater to Santa Monica Bay (Base Case)	---
2	Discharge all wastewater to local sewer system	Not Feasible
3	Reduce wastewater volume and discharge to local sewer	$300,000/yr at avg. usage [1] $2,000,000/yr at peak usage
4	Zero-discharge	Not Feasible
5	Additional reuse of plant waste streams	$200,000/yr at avg. usage [1] $1,500,000/yr at peak usage

[1] Cost based only upon the expense associated with demineralizer operation.

4.7.5 Alternative Cooling Technologies

4.7.5.1 Once-Through Cooling System

Plans for the proposed project include demolition of the existing power blocks of Units 1 and 2 at ESGS and construction of a combined cycle plant within the footprint of the demolished units. Heat rejection for the new steam turbine generator (STG) associated with the new combined cycle plant is proposed to be accomplished with a new deaerating, steam surface condenser connected to the existing heat rejection system, previously utilized by Units 1 and 2 STGs.

The existing heat rejection system to be utilized by ESGS Units 5-7 is a once-through type heat rejection system. The main components of the existing once-through cooling system include circulating water pumps, piping, valves, intake structure, and traveling water screens. The circulating water pumps draw seawater from the Santa Monica Bay and pump the seawater through the deaerating, steam surface condenser. Steam from the steam turbine is condensed in the surface condenser. As steam flows over the outside of the condenser tubes, heat is transferred to the circulating water inside the tubes. The heated circulating water returns to the Santa Monica Bay through the circulating water piping.

Since the project proposes to use the same once through cooling system, flow rates, the number of circulating pipes, the type of circulating pumps, and maximum capacity of 207 million gallons per day will remain the same. In addition, the proposal uses the same water discharge system, which ejects water 10 feet above the seafloor at a depth of 20 feet. Therefore, the proposed project will not exceed the current NPDES permits governing the circulating water flow rate and the thermal discharge limit. Further discussion of environmental impacts of the once-through cooling system have been addressed in Section 5.5 “Water Resources” and Section 5.6 “Biological Resources” of this Application for Certification.

The main advantages of utilizing the once-through heat rejection system include the following:

- The system is currently installed such that minimal new equipment is required. This results in a lower capital cost

- Once-through cooling offers the most efficient steam cycle. This is due to the lower condenser pressures that are achievable when using the cool ocean water temperature as the circulating water source. This results in the highest output and lowest plant heat rate

Therefore, it maximizes the efficiency of power generation relative to other cooling systems

- Lower plant auxiliary power requirements

- The water discharge system minimizes thermal plume through the rapid mixing of cold seafloor water and discharged water

- The system uses a velocity cap proposed by the Federal government as a best available technology for minimizing the impact of water cooling systems on marine resources

- It has no significant adverse impact on both the entrainment and impingement of fish species

- Site area required is lower than any alternatives mitigating land impacts

- Visual impact to the community remains the same and is the least significant and least objectionable when compared to the alternatives.

The main disadvantages for utilizing the once-through heat rejection system include the following:

- Although 100 percent of the seawater withdrawn from Santa Monica Bay is returned to the bay, this alternative passes significantly higher amounts of water through this system as compared to the other alternatives

- The once-through system may impact fish and marine life in Santa Monica Bay. However, the proposal does not result in a significant increase in adverse effects.

The only modifications required for the utilization of the existing once-through cooling system in the new combined cycle plant include the installation of piping and necessary valves between the intake structure and the STG condenser. The total cost (furnish and erect) for the new steam surface condenser and the interconnecting supply and return piping and valves is estimated to be $6,400,000.

4.7.5.2 **Wet Cooling Tower Alternative**

The main components of the wet cooling tower heat rejection system alternative include circulating water pumps, piping, valves, cooling tower, cooling tower basin, and cooling tower basin pump pit. The circulating water pumps draw water from the cooling tower basin and pump water through the deaerating, steam surface condenser. As in the case of the once-through system, steam from the steam turbine is condensed in the surface condenser. As steam from the steam turbine flows over the outside of the condenser tubes, heat is transferred to the circulating water inside the tubes. The heated circulating water flows to the top of the cooling tower and is discharged over the cooling tower fill. The heated circulating water rejects heat to the atmosphere primarily through latent cooling as a percentage of the circulating water is evaporated while falling through the cooling tower fill. The cooled circulating water then collects in the tower basin and is pumped back through the condenser. This alternative considers the use of seawater as the lowest impact medium. The quantity of potable water required by this technology is so large that it is considered infeasible.

The main advantages of the wet cooling tower alternative include the following:

- Although seawater would be used as the source of makeup water for the cooling tower, the water usage is lower than for the once-through heat rejection system

- Although cooling tower blowdown will be discharged to the Santa Monica Bay, the environmental impact on the ocean is reduced when compared to the once-through heat rejection system.

The main disadvantages of the wet cooling tower alternative at ESGS include the following:

- Due to site space constraints, the only potential location for a wet cooling tower on the ESGS property would be approximately 1,800 feet south of the combined cycle plant. Figure 4.7-1 shows the potential location of the wet cooling tower. This location is considered unacceptable for locating the wet cooling tower because of the excessive space constraints it would impose on the site during the construction and operational stages of the ESGS

- Assuming the tower could be located at the south end of the ESGS property, the distant placement of the tower from the combined cycle plant STG will result in substantially higher circulating water piping capital costs than with the once-through cooling system. Operational costs associated with the higher pumping head associated with this wet cooling tower location will be significantly higher than with the once-through cooling system

- The site area requirements are significantly greater for the wet cooling tower option than for the once-through cooling system to accommodate the cooling tower, basin, and the basin pit associated with the circulating water pumps. Furthermore, the piping to and from the cooling tower and condenser has a considerable space requirement. The piping will have to be routed under the ESGS beachfront from the north end to the south end of the ESGS property. Refer to Figure 4.7-1. Construction of the circulating water piping along the beach-front will likely have an unacceptable community impact, as it would require the rerouting of the bike path that currently is adjacent to the plant west fence line negatively affecting the recreational value of the coastal environment;

- The steam cycle is less efficient for the wet cooling tower option than for the once-through cooling system. This results in lower net plant output, higher plant heat rate, and higher auxiliary power consumption. Therefore, more fuel would be needed to produce a level of output equivalent to an unit utilizing the once-through cooling system

- Cooling tower drift emissions, visible plume, noise, and a significantly large, new structure are negative environmental impacts with the utilization of a wet cooling tower that would not exist with the proposed once-through system.

A wet cooling tower to be used in conjunction with the new combined cycle plant STG condenser at ESGS would be a 14-cell tower configured in a back-to-back arrangement (i.e., 2 x 7). The dimensions of each cell would be 48 feet by 48 feet, for a total length and width of the tower of 336 feet by 96 feet, respectively. The long dimension of the tower will need to be oriented in an east-west direction to take advantage of the prevailing winds. Each cell of the wet cooling tower will be equipped with a 200 HP fan.

The total estimated cost (furnish and erect) for the steam surface condenser, cooling tower, cooling tower basin, circulating water pumps, piping, and valves is $18,000,000- nearly three times the cost of the proposed once-through cooling system.

A wet-dry cooling tower (or hybrid tower) was not included in this alternative evaluation primarily because its size would be greater than that of a wet cooling tower, which have greater recreational and visual impacts on the coastal environment. The auxiliary power consumption for a wet-dry tower would also be greater than that of a wet tower. Advantages for a hybrid tower compared to a wet tower typically would include such issues as less makeup water usage and a less visible plume. Nevertheless, this hybrid tower would result in greater spatial, fuel requirements, and plume emissions than the proposed project.

4.7.5.3 <u>Air-Cooled Condenser System</u>

The main components of the air-cooled condenser alternative include an air-cooled condenser, steam ducts, and condensate collection tank. The steam from the steam turbine flows to an air-cooled condenser where the steam is then condensed. The air-cooled condenser accepts steam from the turbine exhaust and conveys it through the steam ducting to finned tubes that are directly exposed to atmosphere. As the condenser fans pull air between the tubes and over the fins, sensible heat transfer to the atmosphere occurs and the steam condenses on the inside of the tubes. Condensate is then collected in a header that drains to the condensate collection tank.

The main advantages of this air-cooled condenser alternative include the following:

- Water usage is minimal compared to the other alternatives
- No drift emissions or visible plume are produced.

The main disadvantages of the air-cooled condenser alternative include the following:

- The capital cost is significantly greater than the other alternatives.

- The site area requirements for an air-cooled condenser are very large. Free site area (an area not currently utilized in the combined cycle plant layout) is not available to accommodate the addition of an air-cooled condenser. An air-cooled condenser must be located in close proximity to the STG or the size of the steam ducting will become too great. For the ESGS site, the only location to place an air-cooled condenser is above the STG operating deck and its associated gantry crane. Figure 4.7-2 shows the only location to place an air-cooled condenser. Locating the air-cooled condenser at a very high elevation (above 90 feet above finish grade) not only increases capital cost to prohibitive levels, but also creates visual and noise impacts that are in excess of the proposed project.

- The steam cycle is significantly less efficient than the other alternatives. This results in lower net plant output, higher heat rate, and higher auxiliary power requirements. Therefore, more fuel is required to produce a comparable level of output than an unit utilizing the proposed system.

- The steam turbine will have to be designed to operate with the exhaust at an elevated pressure and potential suppliers of turbines that can supply such a turbine are extremely limited bringing into doubt the long-term viability of this option.

An air-cooled condenser for the new combined cycle plant STG would be comprised of 45 modules configured in a 9 x 5 arrangement. The overall footprint dimensions of the air-cooled condenser module array are estimated to be 240 feet by 109 feet. Each module of the air-cooled condenser will be equipped with a 200 HP fan.

Because of the site constraints, the air-cooled condenser would have to be erected on a structure high above the STG operating deck. This structure would have to be seismically designed, because ESGS is located within Zone 4 of the California Building Code. Even with the condenser being located above the STG at a point as high as 100 feet above finished grade, interference with the adjacent heat recovery steam generator structures is likely to be unavoidable. Also, steam ducting from the STG below will interfere with adjacent plant components and future maintenance access ways.

Assuming the air-cooled condenser could fit in the space above the STG, the total estimated cost (furnished and erected) of the air-cooled condenser (without including a cost factor for a seismic structure) will be well in excess of $30,000,000. This cost is nearly five times the cost of the proposed system. In addition, the height of the structure has negative visual consequences for the coastal environment.

4.7.5.4 Performance and Efficiency of Cooling Systems

Operating the proposed combined cycle plant with either the wet cooling tower or air-cooled condenser would change the overall performance and efficiency of the project when compared to the base case cooling system alternative - the once-through system. Heat balance analyses were performed to estimate the impacts to performance and efficiency. A summary of the findings of these performance estimates is shown in Table 4.7-4.

TABLE 4.7-4

HEAT BALANCE SUMMARY OF COOLING SYSTEM ALTERNATIVES [1,2,3]

	Once-Through Cooling[4]	Wet Cooling Tower	Air-Cooled Condenser
Output – MWe	641.36	640.17	626.78
Heat Rate – Btu/kW-hr (LHV)	6,773	6,785	6,930
Efficiency	50.38	50.29	49.24

1 All estimates are for peak load operation on the 1 percent ASHRAE hot summer day, 83°F/68°F. Steam injection is on, evaporative coolers is on, maximum HRSG duct firing, and 5 percent overpressure operation.
2 Refer to notes on Figure 3.4-1 in AFC Section 3.0.
3 These performances are estimates and cannot be guaranteed.
4 Feedwater heaters are out of service and heat rejection duty has no limitations.

The results in Table 4.7-4 indicate that a configuration utilizing one of the two alternative technologies would require additional fuel to generate an equivalent amount of net power as the proposed configuration. This increase in fuel consumption would result in greater life-cycle environmental impacts associated with the extraction of natural gas.

4.7.5.5 The Environmental Impacts of the Cooling Systems

A discussion of comparative visual, air quality, and noise impacts of the alternative cooling systems is presented in this section. Visual impacts considered include viewing of additional structures at the site, changes to existing vistas, and viewing of vapor plumes resulting from each cooling system option. Air quality impacts considered include additional impacts induced by structures and additional emissions of pollutants resulting from each cooling system. Noise impacts considered include various noise components, directional considerations, and equipment location considerations for each of the alternatives.

The primary advantage of the wet cooling tower and air-cooled condenser alternatives is that they consume less water than the once-through cooling system. However, both processes require more auxiliary power consumption than the proposed once-through system reducing overall plant efficiency. Therefore, both alternatives would require more fuel to generate an equivalent amount of generation output than the proposed project. This implies that the alternative cooling systems would have more environmental impacts because of the increased extraction and utilization of natural gas. Further, both alternatives would have significant adverse visual, air quality, and noise impacts to the public relative to the once-through cooling system.

Considering each alternative's advantages and disadvantages, cost, water usage, system performance and efficiency, and environmental impacts (visual, air quality, and noise), the once-through cooling alternative offers the most economical, highest performance, and least environmental impact solution for rejecting heat from the new combined cycle plant. In addition to these comparative advantages, it should be noted that the once-through cooling system does not produce any significant adverse impacts on the marine resources of Santa Monica Bay.

4.7.6 Alternative Air Emission Control Technology

4.7.6.1 Definition of Issues and Selection Criteria

The design philosophy of this project is to minimize air emissions. A dry, low NOx (DLN) combustor system will be used to control the NOx concentration exiting each CTG. An additional, post-combustion NOx control system, a selective catalytic NOx reduction (SCR) system, will be provided in each HRSG to further reduce the NOx concentration. The SCR system for each HRSG will inject ammonia into the exhaust gas stream upstream of a catalyst bed that will reduce the nitrogen oxides to inert nitrogen and water. An oxidation catalyst system will also be incorporated into the air quality control system to control emissions of carbon monoxide (CO). The utilization of these mature technologies offers a cost-effective approach emissions mitigation approach that does not impede the overall operation of the plant.

4.7.6.2 Alternative NO_x Control Systems

Nitrogen oxide control methods may be divided into two categories: in-combustor NO_x formation control and post-combustion emission reduction. An in-combustor NO_x formation control process prevents the quantity of NO_x formed in the combustion process. A post-combustion technology reduces the NO_x emissions in the flue gas stream after the NO_x has been formed in the combustion process. Both of these methods may be used alone or in combination to achieve the various degrees of NO_x emissions required. The alternative NOx control systems that were evaluated, but were not chosen for this project are described below.

Steam Injection or Water Injection. NO_x emissions from the combustion turbines can be controlled by either water or steam injection. This type of control injects water or steam into the primary combustion zone with the fuel. The water or steam serves to reduce NO_x formation by reducing the peak flame temperature. The degree of reduction in NO_x formation is proportional to the amount of water injected into the combustion turbine.

Since the combustion turbine New Source Performance Standard (NSPS) was last revised in 1982, manufacturers have improved combustion turbine tolerances to the water necessary to control NO_x emissions below the current NSPS level. A limit exists, however, to the amount of water that can be injected into the system before reliability of the combustion turbine is seriously degraded and operational life affected. This type of control can also be counterproductive with regard to CO and VOC emissions that are formed as a result of incomplete combustion. This control technology was not considered a viable option because

of the water injection limitations and concerns regarding its effectiveness at controlling the above criteria pollutants.

XONON™. Another form of in-combustor control is XONON. This technology, developed by Catalytica Combustion Systems, is designed to avoid the high temperatures created in conventional combustors. The XONON combustor operates below 2,700°F at full power generation, which significantly reduces NO_x emissions without raising and possibly even lowering emissions of CO and unburned hydrocarbons. XONON uses a proprietary flameless process in which fuel and air react on the surface of a catalyst in the turbine combustor to produce energy in the form of hot gases, which drive the turbine.

This technology has been commercially demonstrated in a 1.5 MW natural gas-fired turbine in California and commercial availability of the technology for a 200 MW GE Frame 7G natural gas-fired turbine was recently announced for one project. The combustor used in the demonstration engine is generally comparable in size to that used in GE Frame 7F engines; however, the technology has not been announced commercially for the, Frame 7F engines proposed for this project. General Electric has indicated the technology is not yet commercially available. No turbine vendor, other than General Electric, has indicated the commercial availability of catalytic combustion systems at the present time; therefore, catalytic combustion controls are not available for this specific application and are not a feasible option for the project.

$SCONO_x$™. $SCONO_x$™ is another post-combustion control alternative that was not chosen for this project. This relatively new post-combustion technology is from Goal Line Environmental Technologies and ABB Alstom Power. $SCONO_x$™ utilizes a coated oxidation catalyst to remove both NO_x and CO without a reagent such as ammonia.

The $SCONO_x$ ™ system utilizes hydrogen (H_2), which is created by reforming natural gas, as the basis for a proprietary catalyst regeneration process. The system consists of a platinum-based catalyst coated with potassium carbonate (K_2CO_3) to oxidize both NO_x and CO and thereby reducing total plant emissions. CO emissions are decreased by the oxidation of CO to carbon dioxide (CO_2). The catalyst is installed in the flue gas at a point where the temperature is between 300 to 700°F. When the catalyst reaches the end of its service life, it can be recycled to recover the precious metal contained within the catalyst.

The $SCONO_x$™ catalyst is very susceptible to fouling by sulfur in the flue gas. The impact of sulfur can be minimized by a sulfur absorption $SCOSO_x$ catalyst. The $SCOSO_x$ catalyst is located upstream of the $SCONO_x$™ catalyst. The SO_2 is oxidized to sulfur trioxide (SO_3) by the $SCOSO_x$ catalyst. The SO_3 is then deposited on the catalyst and removed from the catalyst when it is regenerated. The $SCOSO_x$ catalyst is regenerated along with the $SCONO_x$™ catalyst.

Estimates of control system efficiency vary. ABB Environmental has indicated that the SCONOx™ system is capable of achieving a 90 percent reduction in NOx, a 90 percent reduction in CO to a level of 2 ppm, and an 80 percent-85 percent reduction in VOC emissions.[1] Commercially quoted NOx emission rates for the SCONOx™ system range from 2.0 ppm on a 3-hour average basis, representing a 78 percent reduction[2], to 1.0 ppm with no

[1] ABB Environmental, op cit.
[2] ABB TMP, op cit.

averaging period specified (96% reduction)[3]. The SCONOx™ system does not control or reduce emissions of sulfur oxides or particulate matter from the combustion device.[4]

The SCONOx™ system has been applied at the Sunlaw Federal Cogeneration Plant in Vernon California since December 1996, and at the Genetics Institute Facility in Massachusetts. The Sunlaw facility uses an LM-2500 gas turbine, rated at a nominal 23 MWe, and the Genetics Institute facility has a 5 MWe Solar gas turbine. The SCONOx™ system is currently proposed for demonstration by PG&E Generating Company at the Otay Mesa Generating Project. In addition, the technology's co-developer, Sunlaw, has proposed to use the technology in conjunction with ABB gas turbines at the Nueva Azalea site in Southern California.

SCONOx™ results in no emissions of ammonia, while the proposed SCR system will limit ammonia slip levels to 5 ppm. Since SCONOx™ technology to eliminate ammonia slip may be technologically feasible, an evaluation of the cost/effectiveness of this technology was performed. In this analysis, the cost of a SCONOx™ system was compared with the cost of an SCR and oxidation catalyst system, with the incremental cost assigned to the benefit of eliminating ammonia slip emissions. (It is appropriate to make such an assignment because the performance of the SCR and oxidation catalyst systems are comparable to that proposed for SCONOx™ with respect to NOx and CO emission levels for this project.)

As shown in Tables 4.7-5 through 4.7-8, the results of this analysis indicate that the incremental cost/effectiveness of the SCONOx™ system for the purpose of reducing ammonia emissions is nearly $50,000 per ton.

The South Coast AQMD no longer publishes cost/effectiveness criteria for use in performing BACT analysis. In the absence of SCAQMD-specific criteria, the following values are presented to provide a reference for the calculated cost/effectiveness of SCONOx™ as an ammonia control device. Since ammonia is regulated as a precursor to PM_{10}, the values shown below represent the BACT cost/effectiveness thresholds for PM_{10}:

Bay Area AQMD -	$5,300 /ton
San Joaquin Valley Unified APCD -	$5,700 /ton.

While these values are not, by themselves, determinative, they indicate that the cost/ effectiveness of using SCONOx™ to eliminate ammonia emissions is well in excess of costs that are normally required for the control of PM_{10} in BACT determinations in areas of California that exceed the state and/or federal PM_{10} air quality standards.

3 Letter from ABB Alstom Power to Sunlaw Energy Corporation dated February 11, 2000. (ABB Sunlaw).
4 ABB Environmental, op cit.

Based on the above analysis, both SCR and SCONOx™ -based systems are considered, in general, to be technologically capable of achieving NOx levels below 2.5 ppm, given appropriate consideration to turbine outlet NOx levels, catalyst volume (space velocity) and control system design. BACT for NOx is considered to be the use of either SCR or SCONOx™ systems to achieve NOx levels not higher than 2.5 ppm on a 1-hour average basis, or 2.0 ppm on a 3-hour average basis. For the SCR catalyst, BACT for ammonia is considered to be an ammonia slip limit of 5 ppm. SCONOx™ has the potential to eliminate ammonia emissions; however, this candidate technology was rejected because of its cost effectiveness in eliminating ammonia emissions.

4.8 COMPARATIVE ANALYSIS OF ALTERNATIVES

Sections 4.1 to 4.7 present a comparative analysis of alternatives to the existing facility proposal. Since the purpose of this analysis is to evaluate if there are feasible alternatives that could avoid or lessen any significant environmental impacts of the project as proposed by the ESGS site, the following criteria have been used in evaluating a range of alternative technologies and configurations:

- Commercial Availability
- Cost Effectiveness
- Implementability and environmental impact.

The comparative analysis showed the feasibility and environmental impact criteria for operating each of the alternatives, including the No Project alternative, alternative generating technologies, and alternative on-site configurations. While the criteria for these alternatives are not absolute, this section has shown that there are not likely to be any feasible alternatives that would avoid or lessen any significant environmental impacts of the proposed facility.

4.9 CONCLUSIONS

This analysis has undertaken an evaluation of the no project alternative, alternative generating technologies, and alternative on-site configurations and has concluded that the proposed project would not result in any significant environmental effects. Further, this proposal would lead to the creation of a competitive merchant plant that would provide a better financial benefit to ratepayers than the other alternatives that were examined. The points made in the analysis that support this conclusion include:

Table 4.7-5

SCR Costs (per gas turbine/HRSG)

Description of Cost	Cost Factor	Cost ($)	Notes
Direct Capital Costs (DC):			
Purchased Equip. Cost (PE):			
Basic Equipment:			
Auxiliary Equipment: HRSG tube/fin modifications			
Instrumentation: SCR controls			
Ammonia storage system:			
Taxes and freight:			
PE Total:		$1,620,000	1
Direct Install. Costs (DI):			
Foundation & supports:	0.08 PE	$129,600	2
Handling and erection (included in PE cost):		$0	1
Electrical (included in PE cost):		$0	1
Piping (included in PE cost):		$0	1
Insulation (included in PE cost):		$0	1
Painting (included in PE cost):		$0	1
DI Total:		$129,600	
Site preparation for ammonia tanks		$10,000	1
DC Total (PE+DI):		$1,759,600	
Indirect Costs (IC):			
Engineering:	0.10 PE	$162,000	2
Construction and field expenses:	0.05 PE	$81,000	2
Contractor fees:	0.10 PE	$162,000	2
Start-up:	0.02 PE	$32,400	2
Performance testing:	0.01 PE	$16,200	2
Contingencies:	0.05 PE	$81,000	1
IC Total:		$534,600	
Less: Capital cost of initial catalyst charge		-$975,000	
Total Capital Investment (TCI = DC + IC):		$1,319,200	
Direct Annual Costs (DAC): 0.5 hr/SCR per shift	hr/yr: 4,380		
Operating Costs (O): sched. (hr/day 24	day/week: 7 wk/yr: 52		
Operator: hr/shift: 1.0	operator pay ($/hr): 39.20	$42,806	2
Supervisor: 15% of operator		$6,421	2
Maintenance Costs (M): 0.5 hr/SCR per shift			
Labor: hr/shift: 1.0	labor pay ($/hr): 39.2	$42,806	2
Material: % of labor cos 100%		$42,806	2
Utility Costs:			
Perf. loss: (kwh/unit): 347.6			1
Electricity cost ($/kwh): 0.0336	Performance loss cost penalty:	$102,311	5
Ammonia based on 153 lbs/hr of 24.5% wt aqueous ammonia, $0.05/lb		$73,883	1, 4
Catalyst replace: based on 3 year catalyst life		$325,000	1
Catalyst dispose: based on 2,750 ft^3 catalyst, $15/$ft^3$, 3 yr. Life		$13,750	1
Total DAC:		$649,784	
Indirect Annual Costs (IAC):			
Overhead: 60% of O&M		$80,904	2
Administrative:	0.02 TCI	$26,384	2
Insurance:	0.01 TCI	$13,192	2
Property tax:	0.01 TCI	$13,192	2
Total IAC:		$133,672	
Total Annual Cost (DAC + IAC):		$783,456	
Capital Recovery (CR):			
Capital recovery: interest rate (%) 10			
period (years): 15	0.1315	$173,440	2
Total Annualized Costs		$956,897	

Table 4.7-6
Oxidation Catalyst Costs (per gas turbine/HRSG)

Description of Cost	Cost Factor	Cost ($)	Notes
Direct Capital Costs (DC):			
Purchased Equip. Cost (PE):			
Basic Equipment:			
Auxiliary Equipment: HRSG tube/fin modifications			
Instrumentation: oxidation cat. Controls			
Taxes and freight:			
PE Total:		$725,000	1
Direct Install. Costs (DI):			
Foundation & supports:	0.08 PE	$58,000	2
Handling and erection (included in PE cost):		$0	1
Electrical (included in PE cost):		$0	1
Piping (included in PE cost):		$0	1
Insulation (included in PE cost):		$0	1
Painting (included in PE cost):		$0	1
DI Total:		$58,000	
DC Total (PE+DI):		$783,000	
Indirect Costs (IC):			
Engineering:	0.10 PE	$72,500	2
Construction and field expenses:	0.05 PE	$36,250	2
Contractor fees:	0.10 PE	$72,500	2
Start-up:	0.02 PE	$14,500	2
Performance testing:	0.01 PE	$7,250	2
Contingencies:	0.05 PE	$36,250	1
IC Total:		$239,250	
Less: Capital cost of initial catalyst charge		-$350,000	
Total Capital Investment (TCI = DC + IC):		$672,250	
Direct Annual Costs (DAC):	hr/yr: 4,380		
Operating Costs (O): sched. (hr/day 24; day/week: 7	wk/yr: 52		
Operator: hr/shift: 0.0; operator pay ($/hr):	39.20	$0	2
Supervisor: 15% of operator		$0	2
Maintenance Costs (M): 0.5 hr/oxidation cat. per shift			
Labor: hr/shift: 0.0; labor pay ($/hr):	39.2	$0	2
Material: % of labor cos 100%		$0	2
Utility Costs:			
Perf. loss: (kwh/unit): 172.5			1
Electricity cost ($/kwh): 0.0336; Performance loss cost penalty:		$50,773	5
Catalyst replace: based on 3 yr. Life		$116,667	1
Catalyst dispose: based on 240 ft^3 catalyst, $15/ft^3, 3 yr. Life		$1,200	1
Total DAC:		$168,640	
Indirect Annual Costs (IAC):			
Overhead: 60% of O&M		$0	2
Administrative:	0.02 TCI	$13,445	2
Insurance:	0.01 TCI	$6,723	2
Property tax:	0.01 TCI	$6,723	2
Total IAC:		$26,890	
Total Annual Cost (DAC + IAC):		$195,530	
Capital Recovery (CR):			
Capital recovery factor (CRF): interest rate (%): 10			
period (years): 15	0.1315	$88,383	2
Total Annualized Costs		$283,913	

Table 4.7-7

SCONOx™ Cost and Cost/Effectiveness (per gas turbine/HRSG)

Description of Cost		Cost ($)	Notes
Direct Capital Costs			
	Capital (less cost of initial catalyst charge)	$3,900,000	3, 7
	Installation	$1,700,000	3
Indirect Capital Costs			
	Engineering	$200,000	3
	Contingency	$250,000	3
	Other	-	
Total Capital Investment		$6,050,000	
Direct Annual Costs			
	Maintenance	$250,000	3
	Ammonia	-	3
	Steam/Natural Gas	$400,000	3
	Pressure Drop	$226,000	3
	Catalyst Replacement (based on 3-yr catalyst life)	$3,033,333	7, 8
	Catalyst Disposal	$0	
Total Direct Annual Costs		$3,909,333	
Indirect Annual Costs			
	Overhead	-	3
	Administrative, Tax & Insurance	$225,000	3
Total Indirect Annual Costs		$225,000	
TOTAL ANNUAL COST		$4,134,333	
Capital Recovery Factor		0.1315	2
Capital Recovery		$795,416	
TOTAL ANNUALIZED COSTS		$4,929,750	

Table 4.7-8

SCONOx™ Ammonia Cost Effectiveness (per gas turbine/HRSG)

Description of Cost	Cost ($)	Notes
SCONOx Annualized Costs	$4,929,750	
SCR Annualized Costs	$956,897	
Oxidation Cat. Annualized Costs	$283,913	
SCR/Oxidation Cat. Annualized Costs	$1,240,809	
Incremental Annualized Costs	$3,688,940	
Annual Ammonia Emissions with SCR (tons/yr)	74.02	6
Annual Ammonia Emissions with SCONOx (tons/yr)	0	
Reduction in Ammonia Emissions (tons/yr)	74.02	
SCONOx COST EFFECTIVENESS ($/ton removed)	$49,836	

Notes for Tables 4.7-5, 4.7-6, 4.7-7, and 4.7-8

Note No.	Source
1	Based on information from Duke/Fluor Daniel.
2	From EPA/OAQPS Control Cost Manual. EPA-450/3-90-006. January 1990.
3	From April 12, 2000 letter from ABB Alstom Power to Matt Haber EPA Region IX (SCONOx capital cost of $13,000,000).
4	Based on anhydrous ammonia cost of $450/ton.
5	Based on current average price of power in the project area.
6	Based on G.E. 7FA Gas Turbine/HRSG operating at 100% load, 43 deg. F ambient, duct burner on, ammonia slip of 5 ppm @ 15% O2, operating 24 hours per day, 365 days per year.
7	Based on information from May 8, 2000 "Testimony of J. Phyllis Fox, Ph.D. on Behalf of the California Unions for Reliable Energy on Air Quality Impacts of the Elk Hills Power Project", cost of replacement catalyst for SCONOx is 70% of initial capital investment.
8	Based on information from May 5, 2000 letter from ABB Alstom Power to Bibb and Associates indicating that SCONOx catalyst life is guaranteed for a 3-year period.

The No Project Alternative

- This option would exacerbate current market conditions characterized by tight demand and supply conditions. The effect would be more frequent price escalations
- and supply curtailments, while the proposed project would serve to mitigate these adverse effects.

- Less efficient and older power plants would continue to meet increased demand. Continued reliance on such units has an adverse effect on air quality and system reliability compared to the proposed project

- Alternatively, the no project alternative could increase the incentive to construct a new greenfield power generation facility. Such a facility would require the development of additional land and new infrastructure resulting in greater environmental impacts than the proposed project.

Alternative Generating Technologies

- The utilization of alternative gas-fired technologies would involve a host of commercial availability, cost-effectiveness, and air emissions implications. The analysis found that those technologies that were available on a commercial scale similar to the proposed unit were less efficient, and hence, produced more air emissions per MWh than the proposed project.

- Coal-fired technology alternatives would result in greater environmental impacts such as increased truck and train traffic, fuel storage issues, land requirements, and air emissions than the proposed project.
  .
- Hydroelectric generation on a comparable scale as the proposed project would inundate thousands of acres of land, consume freshwater resources, and have recreation, fish and wildlife impacts all of which are avoided by the proposed project.

- The construction of an equivalent scale wind project would require 25,000 acres of land, while proposed project requires 5.5 acres. This alternative also creates environmental impacts such as noise, visual, and avian mortality, which are absent from the proposed project. Further, this technology would not be able to produce electricity as reliably as the proposed project.

- The development of a solar power station capable of providing an equivalent amount of power as the proposed project would require an infeasible amount of spatial resources. Further, this alternative does not enhance reliability and would generate power at an additional cost of least 10 cents per kWh relative to the proposed project.

Alternative Onsite Configurations

- Replacing the existing boilers in kind would result in the utilization of a less efficient technology that would produce more emissions per MWh generated than the proposed project.

- The smaller scale alternative of one 250 MW turbine at the project site has an adverse affect on the economics of the proposal. This, in turn, would affect the feasibility of utilizing technologies that lead to the most efficient use of water and the construction of the ammonia pipeline.

- The use of either wet-cooling tower or air-cooled condenser systems would reduce the amount of net generation compared to the proposed once-through cooling system. Therefore, these alternatives create additional environmental impacts resulting from the need to consume additional natural gas to produce an equivalent amount of electricity as the proposed configuration. Further, both of these alternatives would result in more visual, air, and noise impacts than the proposed configuration.

- The proposed dry, low NO_x (DLN) combustor system and additional, post-combustion NO_x control system, a selective catalytic NO_x reduction (SCR) system in each HRSG offers the best configuration at the proposed unit size. Alternative emission control technologies either face water input limitations, uncertainty that they could be effective given the project's capacity, or reduce net power generation relative to the proposed configuration.

The analysis developed in this chapter demonstrates that there are no alternatives to the proposed project design that either are feasible, or would materially lessen any potential adverse environmental effect of the proposed project. Further, the proposed configuration offers the most cost-effective project for participating in the merchant power market. There is no feasible alternative project configuration, generation technology or non-generation technology. As a result, it is concluded that the proposed combined-cycle project using natural gas is the best available technology and the use of the existing plant site is the best location to site the El Segundo Power Redevelopment Project.

Adequacy Issue: Adequate ____ Inadequate ____

DATA ADEQUACY WORKSHEET

Revision No. 0 Date ________

Technical Area: **Alternatives** Project: ________ Technical Staff: ________

Project Manager: ________ Docket: ________ Technical Senior: ________

Siting Regulations	Information	AFC Page Number And Section Number	Adequate Yes Or No	Information Required To Make AFC Conform With Regulations
Appendix B (b) (1) (D)	A description of how the site and related facilities were selected and the consideration given to engineering constraints, site geology, environmental impacts, water, waste and fuel constraints, electric transmission constraints, and any other factors considered by the applicant.	Section 4.1 to Section 4.3 Pages 4-1 to 4-3		
Appendix B (f) (1)	A discussion of the range of reasonable alternatives to the project, or to the location of the project, including the no project alternative, which would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project, and an evaluation of the comparative merits of the alternatives. In accordance with Public Resources Code section 25540.6(b), a discussion of the applicant's site selection criteria, any alternative sites considered for the project, and the reasons why the applicant chose the proposed site.	Section 4.4 to Section 4.9 Pages 4-3 to 4-22		
Appendix B (f) (2)	An evaluation of the comparative engineering, economic, and environmental merits of the alternatives discussed in subsection (f)(1).	Section 4.4 to Section 4.9 Pages 4-3 to 4-22		